Service Date: April 22, 1988

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER Of the Application Of MONTANA POWER COMPANY to Restructure Electrical Rates.)	Docket No. 87.4.21
IN THE MATTER Of the Application Of MONTANA POWER COMPANY For Authority To Implement an Electric Economic Incentive Rate.)	Docket No. 86.6.29
IN THE MATTER Of the Application Of MONTANA POWER COMPANY For Authority To Establish An Electric Industrial Retention/Interruptible Rate For Stauffer Chemical Co.)	Docket No. 85.9.40
IN THE MATTER Of the Application Of MONTANA POWER COMPANY To Change The Availability Criteria In The Electric Contract Tariff.)	Docket No. 85.11.49
IN THE MATTER Of the Complaint Of MONTANA REFINING COMPANY, Complaintant, vs. MONTANA POWER COMPANY, Defendant.)	Docket No. 86.12.50 ORDER NO. 5340

APPEARANCES

FOR THE APPLICANT:

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BEFORE:

CLYDE JARVIS, Chairman, Presiding
HOWARD L. ELLIS, Commissioner
TOM MONAHAN, Commissioner
DANNY OBERG, Commissioner
JOHN B. DRISCOLL, Commissioner

FINDINGS OF FACT

PART A

BACKGROUND

The Montana Power Company (hereafter MPC, Company, or Applicant) is a public utility furnishing electric service in the State of Montana, and is subject to the regulatory jurisdiction of the Public Service Commission (PSC or Commission). The Company serves approximately 242,000 electric customers in Montana.

On April 9, 1987, MPC filed with the Commission its application for authority to restructure electric rates.

On June 1, 1987, the Commission issued a Notice of Application and Proposed Consolidation and Procedural Order. The dockets consolidated into this proceeding are; 1) Docket No. 86.6.29, Economic Incentive Rate, 2) Docket No. 85.9.40, Industrial Retention/Interruptible Rate, 3) Docket No. 85.11.49, Electric Contract Tariff Availability Criteria, and 4) Docket No. 85.12.50, Montana Refining Company Complaint.

The Commission granted the Motion to Intervene of the Montana Consumer Counsel (MCC) on July 1, 1987, and the MCC has participated in this Docket on behalf of electric utility customers since the inception of these proceedings..

On July 1, 1987, the Commission issued a Notice of Staff Action granting the Petitions to Intervene of the following parties:

ASARCO Incorporated

Exxon Company, U.S.A.

Ideal Basic Industries

Conoco, Incorporated

District XI Human Resources Council

Stone Container Corporation.

Montana Refining Company

Montana Low Income Coalition

Butte Community Union

Low Income Group for Humane Treatment

Montana Senior Citizens Association

Concerned Citizens Coalition

On July 20, 1987, August 24, September 4 and September 28, 1988, the Commission issued a Notice of Staff Action which amended the Procedural Order in this Docket without changing the hearing date.

On July 23, 1987, the Commission issued a Notice of Staff Action granting the request of Great Falls Gas to intervene in this proceeding.

On July 30, the Commission issued a Notice of Staff Action which granted an extension of time for the filing of testimony by ASARCO, Inc., Conoco, Inc., Exxon Company U.S.A., Ideal Basic Industries, and Stone Container Corp. (hereafter IND, ASARCO et al., or Industrials).

On September 8, 1987, the Commission at its regularly scheduled agenda meeting, dismissed the Complaint in Docket No. 85.12.50.

The Commission, at its regularly scheduled agenda meeting held September 28, 1987, granted Champion International Corporation's Petition for Late Intervention in this proceeding providing that the intervention would not prejudice existing parties or delay the proceedings.

On October 14, 1987, the Commission issued a Notice of Public Hearing to consider MPC's application. The notice was served upon all parties in the Docket and appeared in the Billings Gazette, the Bozeman Daily Chronicle, the Montana Standard,the Great Falls Tribune, the Ravalli Republic, the Havre Daily News, The Independent Record, the Livingston Enterprise, the Mile City Star, and The Missoulian.

Intervenors sponsoring prefiled testimony in this proceeding included the following parties: the MCC, District XI Human Resources Council (hereafter HRC), and the Industrial Intervenors.

Pursuant to the Notice of Public Hearing, a hearing was held in Helena, Montana, commencing on Monday, November 2, 1987 and ending on Thursday, November 5, 1987.

The Commission will not address rate design issues in this Order. The final determination of an appropriate rate design depends largely upon the results of the COS study. In rebut tal testimony, the Company presented the results of its COS study based upon its 1987 Loads and Resources Plan (Exh. 6, Exh. PEM-1). In this Order, the Commission requires that the Company revise its COS study to incorporate the 1987 Plan in developing a COS study in compliance with this Order. The Commission believes the revisions required by this Order will have significant impacts upon the subsequent determination of an appropriate rate design. Accordingly, the Commission feels that it is appropriate to first review the COS results from MPC's compliance with this Order before presenting its findings on rate design. The Commission considers MPC's proposed Electric Economic Incentive and Electric Industrial Retention/Interruptible Rates to be rate design issues, therefore these issues will be addressed with other rate design issues in a later order.

The remainder of this Order addresses only the Cost of Service (COS) and Reconciliation issues in this proceeding.

PART B

COST OF SERVICE

Prior to MPC's filing of Docket No. 87.4.21, the Commission's most recent decisions on MPC cost of service (COS) and rate design (RD) stemmed from Order Nos. 5051d through 5051g, in Docket No. 83.9.67. Order No. 5051d (issued August 3, 1984) accepted the use of a Base-Peak marginal cost study, real carrying charges, and equi-proportional reconciliation (Order No. 5051d, Finding Nos. 70,91,169).

This section of the Order reviews each party's proposals regarding Cost of Service (COS) issues in this proceeding. After these proposals are reviewed, the Commission presents its findings.

MPC Cost of Service

Overview. The MPC uses its Allocated Cost of Service Study to measure long-run marginal costs. Table 1 below illustrates MPC's COS and RD study. The Company first function-alizes total plant into generation, transmission, and distribution. Each of these functions are broken down into separate cost classifications. Each cost classification is then allocated to seasons and customer class. Customer costs are also a function of MPC's COS study. Customer costs are measured on $/customer basis and no further allocation is needed.

Table 1. MPC Cost of Service/Rate Design Model

Function	Cost of Service Classified	Allocated	Reconciled	Rate Design
Generation Transmission Distribution	Capacity, Energy & Customer Access	Seasons and Customer Classes	Equi- Proportional	¢/kwh $/kw $/Customer

Changes to COS. The Company is proposing four major changes to its COS study from the COS study approved in Docket No. 83.9.67, Order No. 5051d. Those changes are:

1. The Company measures marginal generation capacity and energy using a 25-year real levelized cost obtained from its 1986 Loads and Resources Plan (1986 Plan), not the Base-Peak model accepted in Order No. 5051d (Exh. 5, p. 11).
2. The winter season has been increased from four to five months, adding the month of March to the winter season (Exh. 5, p. 17).
3. The Company has changed the allocation of capacity costs to seasons from 87 percent winter and 13 percent summer to 60 percent winter and 40 percent summer (Exh. 5, p. 19).
4. The Company proposes to assign marginal energy costs to seasons, with 57 percent of the costs assigned to the winter season and 43 percent to the summer. Marginal energy costs were not seasonally differentiated in Docket No. 83.9.67 (Exh. 5, p. 6).

Additionally, the Company proposes to treat the electric loads associated with the Electric Economic Incentive Rate (EEI) and the Electric Industrial Retention/Interruptible Rate (EIRI) in the following manner:

1. The Company does not include the capacity or energy associated with the EEI tariff, Montana Resources Inc. (MRI), in its COS study.
2. The Company does include the capacity and energy associated with the EIRI tariff, Stauffer, in its COS study.

Rebuttal - COS. In rebuttal testimony, the Company presents an updated COS study which incorporates many changes brought out in the discovery process by Commission staff and intervenors. This updated COS study is included in the record of this proceeding as the Company's response to data request (RDR) PSC 1-31, and is subsequently referred to as the "updated marginal cost study." The changes reflected in the updated marginal cost study are:

1. The MPC's original calculation of long-run marginal energy costs contained an error. The Company corrects

the error, which changes the marginal cost of energy from 2.482 ¢/kwh to 2.2366 ¢/kwh (MPC RDR MCC 1-65).

2. The Company's COS study divides the General Service (GS) rate class into two subclasses based on voltage level of service (primary or secondary). In the updated COS study, MPC places 32% of the GS rate class into the primary voltage subclass,compared to 34% in the original filing (MPC RDR IND 2-1).

3. 500 kV transmission plant is excluded from new load plant. The original filing's inclusion of these costs in new load transmission plant was in error (MPC RDR HRC 1-46).

4. The Company made an error in the allocation of total non-plant related A&G plant costs to functionalized costs. This error is corrected in MPC's updated marginal cost study (MPC RDR HRC 1-63).

5. The Company did not include any A&G plant related costs in the calculation of customer plant costs in its original filing. The updated marginal cost study includes these costs (MPC RDR HRC 1-57).

6. Seasonal line losses are developed and used in spreading generation, transmission, and distribution capacity, and generation energy to customer classes by season. In its original COS study, the Company used monthly line losses to calculate an average annual line loss, which it then applied to each season (see MPC RDR PSC 1-31).

Aside from the changes listed above, the Company's updated marginal cost study remains the same as the COS study originally filed.

Generation. MPC uses the cost of a BPA New Resource (NR) purchase to measure marginal generation demand costs, which is consistent with the Company's 1986 Loads and Resources Plan (1986 Plan) (Exh. 5, p. 21). The 25-year real levelized cost of a BPA NR-87 purchase is used to calculate long-run marginal generation demand costs of 56.971 $/kw (MPC RDR MCC 1-65). Marginal generation demand costs are further allocated by class and season (see Finding No. 37).

Long-run marginal energy costs are also measured using a 25-year levelized cost, as forecast by MPC's 1986 Plan. The first four years of energy costs are calculated using PROMOD (a system simulation model) and the remaining 21 years are measured using BPA

NR-87 rates (Exh. 5, p. 20). The resulting real levelized marginal generation energy cost is 2.2366 ¢/kwh (MPC RDR MCC 1-65). Marginal generation energy costs are further allocated by class and season (see Finding No. 39).

Transmission. The Company's marginal transmission demand costs are based on the investment and operation and maintenance (O&M) costs to supply an incremental kw on the transmission system (Exh. 5, p. 21). Four years of planned investment in transmission plant are allocated by the Company on a project-by-project basis as investments to accommodate "New Load", or investments to improve system "Reliability" (Exh. 5, p. 22). New Load transmission investments are divided by incremental load growth for the forecast period, resulting in marginal transmission New Load plant costs of 137.12 $/kw (MPC RDR IND 2-1). Similarly, Reliability-related costs are divided by the amount of energy made more reliable to obtain marginal transmission reliability costs of 1.89 ¢/kw. Each of these costs are then annualized using a real carrying charge of 7.02% and adjusted using loaders for plant related A&G expenses and general & common plant expenses (MPC RDR IND 2-1).

Transmission related O&M expenses are calculated using FERC accounts 560 through 573 and the transmission related portion of account 592. Five years of expenses (1981-1985) are escalated to 1987 dollars and allocated to "new load" and "reliability" in the same proportion as transmission plant. The "new load" incremental O&M expense is then divided by the growth in system peak to obtain marginal transmission "new load" O&M costs. The "reliability" incremental O&M expense is divided by growth in system energy, resulting in marginal transmission "reliability" O&M costs. Marginal transmission "new load" and "reliability" costs are then adjusted using a loader for non-plant related A&G expenses (Exh. 1, pp. 23/137, 24/137).

Marginal transmission O&M costs are then added to marginal transmission plant costs to obtain total marginal transmission plant. Total transmission plant is then adjusted for working capital, resulting in total New Load marginal costs of 34.34 $/kw and Reliability marginal costs of 0.3 ¢/kwh (MPC RDR IND 2-1). New Load marginal transmission costs are further allocated to class and season (see Finding No. 37).

<u>Distribution</u>. The Company's marginal distribution costs are based on the investment in distribution plant and O&M costs

needed to supply an additional kw on the distribution system. Included in these costs are general and common plant investment, A&G and general O&M expenses, and working capital associated with the distribution system (Exh. 5, p. 24).

The Company calculates marginal distribution plant using four years of historical investments, retirements, and load growth. The Company measures investments and retirements in distribution plant using FERC accounts 360 through 368, while historic load growth is measured using historical non-coincident peaks which are not normalized. Historical investments are escalated to 1987 dollars, and plant retirements are escalated to 1987 construction costs using a Handy-Whitman index to estimate replacement costs. Investment costs less replacement costs are divided by historical load growth, resulting in the Company's measurement of marginal distribution plant. Marginal distribution plant is then allocated to either primary or secondary distribution plant. All distribution plant is considered to be primary, with the exception of line transformers. Line transformers are allocated to secondary costs, while all plant beyond the transformer, (service drops, meters, etc.), is allocated to customer costs (Exh. 5, p. 25).

Distribution O&M expenses are calculated using FERC accounts 580 through 595 and the distribution portion of account 592. The distribution O&M expense calculation uses the same methodology as transmission O&M expenses (Exh. 5, p. 26).

Customer. The Company's marginal customer costs are based on the customer plant investment and O&M costs needed to supply service to an additional customer, and are calculated using a study performed by the Company's Distribution Engineering Department. Additionally, customer costs for the lighting classes are adjusted to include the costs of fixtures, lamps, and the associated plant and O&M expense (Exh. 5, p. 27).

The Company allocates marginal customer O&M expenses to the various customer classes based on the average cost per customer and plant cost by class. The Company assumes that half of the customer O&M costs are the same for each class, and that the other half is a function of the relative cost of plant required by each customer. O&M expenses are allocated to meter and non-meter related expenses using embedded expense data, and then escalated to 1987 dollars (Exh. 5, p. 27).

Seasonality. This section discusses MPC's determination of seasons and the allocation of demand and energy costs to those seasons. To determine seasons, MPC uses Analysis of Variance (ANOVA) and cost and loss of load hour data by season. ANOVA is a statistical technique used to determine whether two groups of data are significantly different (Exh. 7, p. 16).

For demand, ANOVA is performed on MPC's Loss of Load Hours (LOLH) by month, which is the probability that demand will exceed capacity. The Company's analysis indicates that LOLH is likely to occur 63% of the time in the winter, and 37% of the time in the summer. Accordingly, MPC proposes to allocate 60% of marginal demand costs to the winter, and 40% to the summer, for a 60/40 winter summer allocation (Exh. 15, pp. 19-20).

For energy, ANOVA is performed on MPC's marginal running costs by month. The Company's analysis indicates that 57 percent of its energy costs occur in the winter, and 43 percent in the summer. The Company proposes to allocate marginal energy costs using a ratio of the average seasonal energy costs to average annual costs (Exh. 1, pp. 1/137, 46/137).

The Company restricted the scope of its analysis to the current seasonal definition, plus or minus one month in spring and fall (Exh. 5, pp. 16, 17). Based on the results of ANOVA on both demand and energy, MPC proposes to add the month of March on to its current winter season, extending the winter season to five months. The Company's proposal defines the months of November through March as the winter season, and April through October as the summer (Exh. 5, p. 17).

Allocation of Costs. The allocation of classified costs to customers and season is the next step in MPC's COS study. The allocation of demand costs will be presented first, followed by a similar discussion for energy costs.

The Company allocates marginal generation and transmission capacity costs to customer classes by season on the basis of each class' contribution to the seasonally normalized system peak, and seasonal capacity losses by voltage level of service (Exh. 5, pp. 3/6, 4/6). Marginal distribution capacity costs are allocated to customer classes by season on the basis of the class' non-coincident peak, and seasonal capacity losses by voltage level of service (MPC RDR PSC 1-31).

The Company uses the normalized winter and summer system peaks to spread marginal capacity costs to customer classes. The winter normalized system peak is measured as the single largest winter peak. The summer normalized system peak is measured using an average of all summer peaks. This methodology was accepted in Docket No. 83.9.67. and results in a W/S peak ratio of 1.18, meaning that the winter peak is 18 percent larger than the summer peak.

The MPC also allocates marginal generation energy costs to customer classes by season. Normalized kWh sales by season and line losses by season provide the basis for this classification (MPC RDR PSC 1-31).

MCC Cost of Service

Overview. The marginal COS/RD study presented by the Montana Consumer Counsel (MCC), Mr. Drzemiecki, differs from the Company's COS analysis in the steps it takes to arrive at final prices. Table 2 below illustrates the MCC's COS/RD study.

Table 2. MCC Cost of Service/Rate Design Model

	Cost of Service			
Function	Classified	Allocated	Reconciled Rate Design	
Bulk Power Distribution	Capacity, Energy & Customer Access	Seasons and Customer Classes	Bulk Power Adjustment	¢/kwh $/kw $/Customer

The MPC functionalizes total utility plant into generation, transmission, and distribution costs, while the MCC functionalizes total plant into bulk power supply, and distribution costs. Mr. Drzemiecki provides the basis for this classification:

> A separation of bulk power supply costs from other system costs is appropriate because they are over three-fourths of the total costs of the electrical supply and they are also the costs that vary most by time of use (Exh. 18, p. 24).

Bulk Power is, in turn, comprised of generation and higher voltage transmission plant. Specifically, Bulk Power costs include generation capacity and energy costs, and transmission capacity costs. Theoretically, the MCC proposes to measure MPC's Bulk Power costs using the costs of a combustion turbine (CT) peaking unit.

> The marginal cost of meeting peak demand is the annual carrying cost of of additional capacity that must be added only for the purpose of meeting that additional demand. The cost of meeting additional peak demand will, therefore, never exceed the carrying cost of that generating unit with the lowest fixed cost per kw of capacity (Exh. 18, p. 31).

However, in practice the MCC uses the Company's marginal generation capacity costs to measure that portion of Bulk Power costs. Additionally, the MCC uses the Company's long-run marginal costs of energy, instead of using the costs of running a CT to measure Bulk Power energy costs (Exh. 18, pp. 47-48, and MPC RDR MCC No. 1-65). Bulk Power energy costs are further allocated to seasons using the Company's methodology and MCC's seasonal definition (MPC RDR IND 2-1, Exh. 1, p. 1/137).

The MCC does retain the use of a CT to calculate the marginal transmission capacity cost portion of the Bulk Power Supply. The Company did not provide the MCC with the costs of a CT, so the MCC used cost estimates provided by Montana Dakota Utilities as a proxy for MPC's costs (TR pp.108-109, MCC RDR MPC 1-17). The cost of connecting a CT to the existing transmission system (35.00 $/kw) is annualized using a 16.18 percent nominal carrying charge and adjusted for fixed O&M expenses and reserve requirements, resulting in a long-run marginal cost of transmission demand of 6.74 $/kw (Exh. 19, J.D.-1, p. 3 of 5). Bulk Power capacity costs are then adjusted for capacity losses and allocated to seasons (see Finding No. 48).

Originally, and unlike the Company, the MCC to include 28 MW of firm load associated with the 48 MW EEI load in its COS study. However, Mr. Drzemiecki later proposed excluding this load from the MCC COS study (TR p. 374).

Distribution. The MCC calculates distribution costs using the Company's embedded costs of distribution, as listed in MPC's FERC Form No. 1, accounts 360 through 368. The MCC classifies the total investment in these accounts as demand related and allocates them to customer classes on the basis of each class' non-coincident peak demand. The MCC uses these embedded costs to "approximate" marginal distribution costs (Exh. 18, pp. 49-50).

Customer. Customer costs in the MCC's COS study are approximated using the Company's embedded billing related costs. Those costs are the average annual installed costs for meters and service drops, and costs that can be attributed to accounting, service and information, and meter O&M expenses (Exh. 18, p. 27).

Seasonality. Based on the results of the Company's seasonality study, the MCC concludes that MPC's demand and energy costs vary by season. The MCC adopts the maximum six month seasonal definition supported by the Company's ANOVA study, which defines October through March to be the "winter" season, and April through September to be the "summer" season.

Allocation of Classified Costs. The MCC allocates Bulk Power capacity costs to customer classes by season on the basis of each class' contribution to the seasonally normalized system peak, and capacity losses by voltage level of service (MCC RDR PSC-37). Unlike the Company, which bases this classification on a single winter peak and an average summer peak (see Finding No. 38), the MCC bases this classification on a single peak for the winter and summer season (MPC RDR PSC-37, and MCC RDR IND 2-1, p. 16/23).

Bulk Power energy costs are also classified to customer classes by season. Normalized kwh sales by season, adjusted for line losses, provide the basis for this classification. Line losses are determined by the level at which a class takes service, which in turn determines marginal transmission and distribution energy costs by class (MCC RDR PSC-13, MPC RDR MCC 1-65, Exh. 1, p. 1/137, and Exh. 5, PEM-2, p. 1/6).

HRC Cost of Service

District XI Human Resource Council did not submit a cost of service study in this docket. However, the Council's witness, Dr. Power, has provided prefiled testimony which analyzes the Company's COS study and makes recommendations resulting from that analysis.

MPC's Cost of Service Study. Generally, Dr. Power agrees with MPC's use of long-run marginal costs to assign cost responsibilities to customer classes (Exh. 16, p. 6). However, Dr. Power does disagree with the Company on the development and use of those marginal costs.

MPC uses BPA's New Resource (NR) rates to measure long-run marginal capacity costs. Dr. Power contends that the BPA NR rate is an average regional cost, and is not reflective of regional marginal costs. Furthermore, Dr. Power points out that MPC does not actually plan to purchase BPA NR power, relying instead on the lower cost resources contained in its 1987 Loads and Resources Plan (1987 Plan). Dr. Power argues that if MPC, and the other regional utilities who base their marginal costs on the NR rate, actually make those purchases, it will cause the BPA NR rate to increase. Instead, Dr. Power recommends basing marginal costs on actual resources MPC will use to meet new load.

> I would urge the Commission to order MPC to develop a marginal cost analysis based on the actual resources that will be developed within the region to serve new loads. These could be MPC's incremental resources or they could be the resources that BPA and the Regional Council expect to be developed to serve incremental load (Exh. 16, p. 11).

Dr. Power points out that MPC's most recent avoided cost filing uses its 1987 Plan as the basis for determining avoided cost payments to Qualifying Facilities (QFs). The first two years of the 1987 Plan specify the Bird plant as MPC's marginal resource, with a Washington Water Power purchase listed as its marginal resource for the next two years. The remaining 21 years consist of BPA NR purchases.

Dr. Power's second major criticism of the Company's marginal cost study relates to the accuracy of the COS study. Dr. Power contends that inherent inaccuracies in forecasts used in marginal cost studies limit the application of the results of those studies (Exh. 16, pp. 13-21). Dr. Power asserts that the Company's COS study is accurate only to within plus or minus five percent. Therefore, Dr. Power recommends that the results of the COS only be used to correct rates that are significantly out of line:

> Customer classes whose rates are revealed by the cost of service analysis to be within five or ten percent of their allocated costs should be seen as paying appropriately cost-based rates. Such customers do not need their rates adjusted(Exh. 16, p. 21).

Lastly, Dr. Power criticizes the Company's seasonality study. Dr. Power points out that if the Company had not constrained its analysis, that the results of the analysis would have indicated that an eight or nine month "high load" season is the most appropriate seasonal definition. Dr. Power recommends that the Commission adopt no seasonal differentiation in rates. As a second choice, Dr. Power recommends that the Commission set a nine month "high load" season, July through March, and a three month "low load" season, April through June (Exh. 16, p. 41).

ASARCO et al. Cost of Service

The industrial intervenors did not submit a cost of service study in this docket. However, Mr. Michael and Ms. Wetmore do provide an analysis of the Company's and the MCC's COS studies, and recommendations based upon that analysis.

In rebuttal testimony, Mr. Michael provides an analysis of the impact of the Company's alternative rate design proposal on the Company's COS study. Based on this analysis, Mr. Michael recommends that the Commission require MPC to re-run its COS study to reflect the new GS-1/GS-2 level of service definitions, and then design rates accordingly (Exh. 24, pp. 8-10).

Mr. Michael also provides recommendations regarding seasonal definitions in his rebuttal testimony. Specifically, Mr. Michael recommends adopting a 9 month "high load" season, or no seasons at all. Mr. Michael's preference is for the latter recommendation if seasons are to be retained. He also argues that there is little cost difference to justify a gradual phase-in of any seasonal change (Exh. 24, p. 15).

Dr. Power presents a number of arguments relating to the inherent inaccuracies of the Company's COS study, and the significance of the results (see Finding No. 54). Mr. Michael endorses Dr. Power's findings and recommends no tariff changes for the Residential, General Electric, or Electric Contract rate classes in this proceeding (Exh. 24, p. 21).

Commission Decisions on Cost of Service

Introduction. The Commission would first like to summarize its philosophy on the use of marginal costs in cost of service and rate design. The Commission agrees with MPC, when it states that, "rates based on marginal costs are "fair" to all ratepayers" (Exh. 7, p. 4). As stated by the MCC, "the use of marginal costs will lead to a rate structure that meets the objectives of encouraging conservation, efficiency, and equity" (Exh. 18, p. 12). As has been the Commission's policy in previous dockets, it is appropriate , as the MCC has recommended here, to use marginal costs to determine both inter-class and intra-class revenue responsibility (Exh. 18, p. 13).

Test Year Dollars. The Commission believes that a marginal cost study will not reflect a "true" estimate of marginal costs unless it is presented in terms of dollars reflective of the time period for which rates will be in effect. Therefore, the Commission requires that the revised cost of service study to be filed in compliance with this Order reflect July 1, 1989 dollars.

The Commission requires the MPC to update functionalized marginal costs in the following manner. For marginal generation capacity and energy, refer to Finding No. 68. All remaining functionalized costs components are to be escalated to mid year 1989 dollars using a 4.5 percent escalation rate , which is consistent with the escalation rate contained in MPC RDR PSC 3-29.

Carrying Charges. The Commission chooses to follow its precedent set forth in Docket No. 83.9.67, Order No. 5051d, Finding No. 91, and accept MPC's use of real carrying charges, rather than MCC's proposal to use nominal carrying charges. The Commission finds that the MPC correctly calculates marginal generation capacity and energy costs using forecasted costs which are discounted levelized in real terms. The Company's capital recovery factor,

$$C = \frac{(1+r)^n}{(1+r)^n - 1},$$

where: C = Capital cost recovery factor
r = Real rate of interest
n = Number of years

is easily understood and is based upon a widely accepted formula. Finally, as a policy matter, the Commission has not deviated from the use of real carrying charges in any recent order. (Docket Nos. 86.12.76, 86.5.28, 84.10.64, 83.1.2).

Generation. To summarize, the Commission finds the MPC's development of marginal capacity costs to be incomplete. MCC's

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[1]EPRI Electric Utility Rate Design Study, September 1981. "#93A Cost and Rates Workbook." pgs. 2-5.

marginal capacity costs are based on the Company's esti mates, and therefore the Commission finds the MCC's development of marginal capacity costs are also incomplete. The Commission accepts the Company's proposed marginal capacity costs as revised to include all changes required by this Order. For clarification, the COS study required by this Order will be referred to as the "revised COS study" to distinguish it from the "updated COS study" proposed by MPC in rebuttal testimony.

As previously explained in Finding No. ??, the Company uses 1986 Plan to develop long run marginal generation capacity and energy costs in its COS study, while using its 1987 Plan to develop avoided cost payments to QFs (Exh. 14, p. 12). Mr. Haffey provides an explanation for this inconsistency in his rebuttal testimony.

> Q. You stated that your testimony would also address the Company's use of a different resource plan in its marginal cost study than it did in its most recent Qualifying Facility (QF) rate filing. Why were different plans used?

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[1]EPRI Electric Utility Rate Design Study, September 1981. "#93A Cost and Rates Workbook." pgs. 2-5.

> A. Simply because of a difference in timing. This case was filed in April of this year. Therefore, the resource plan used in determining long-run capacity and energy charges was the 1986 plan. The 1987 plan was published shortly after this case was filed and was used in calculating the new rate for qualifying facilities (QF).
>
> Q. Shouldn't the resource plan used to determine the QF rates and used in the marginal cost study be consistent?
>
> A. Yes, we believe they should be. Unfortunately, timing differences have meant that consistency is not possible
>
> Q. Has MPC computed its marginal costs using the 1987 resource plan?
>
> A. Yes.
>
> Q. And what are the results?
>
> A. As Mr. Maxwell's and Dr. Spann's testimony will explain, the change in resource plans made very little difference in the moderated class revenue responsibilities. Because the difference is so small, we believe that the filed study is still appropriate for the Commission's use (Exh. 14, pp. 12,13).

The Commission agrees with Dr. Power when he states, "This Commission should not be simultaneously lowering capacity payment to QFs while raising capacity charges to retail customers." (Exh. 16, p. 11). The Commission believes that the marginal resources used to calculate marginal costs and avoided costs should be consistent. Based on the above testimony, the Commission requires MPC to file a revised COS study based on its 1987 Plan.

The Commission requires MPC to present the results of its revised COS study in mid-year 1989 dollars (see Finding No. ??). The Company will re-calculate its Energy Rate and Capacity rate Computations contained in Exhibit 6, PEM-1, p. 10/11, and p. 11/11. Using the same methodology contained in those exhibits, MPC is to drop the first two years data and use mid-year 1989 as the starting point for a 25 year energy and capacity rate calculation. The real levelized capacity and energy rates are to be expressed in terms of mid-year 1989 dollars.

In issuing the previous Finding, the Commission is aware that the capacity values on page 11 of PEM-1 represents a 63/37 winter summer cost allocation. The Commission finds the Company's 63/37 allocation to be direct application of the results of the its seasonality of demand analysis (Exh. 1, p. 70/137). The Commission finds the 63/37 allocation preferable to the Company's proposed 60/40 allocation, and requires the Company to retain the use of a 63/37 allocation in its revised COS study.

Seasonality. The Commission would first like to review each party's seasonal recommendations. Table 3 below shows the seasonal recommendations of each party in the docket.

Table 3. Seasonal Proposals

Party		Winter	Summer
MPC	1.	November - March	April - October
MCC	1.	October - March	April - September
HRC	1.	No seasonal variation in rates	
	2.	July - March	April - June
IND	1.	No seasonal variation in rates	
	2.	August - March	April - July
	3.	July - March	April - June

The Commission would like to note the the Company has developed its proposals for seasonally differentiated rates utilizing an Analysis of Variance (ANOVA) study for both demand and energy (see Finding No. ??). Additionally, the Commission notes that MPC's methodology has been the basis for all party's seasonal recommendations in this proceeding.

The Company's seasonality of energy ANOVA study utilizes hourly marginal costs in determining seasons. During cross examination, Mr. Drzemiecki testified that the Company's analysis might be improved if transmission level line losses were added to hourly marginal costs (TR pp. 379-380). The Commission agrees with Mr. Drzemiecki, and requires MPC to add transmission level line losses on to hourly marginal costs for the purposes of determining seasonality of energy in its next general rate filing. The Commission also requires MPC to study the feasibility of including capacity losses in its demand seasonality study as well.

Table 4 below illustrates the effect adding transmission level line losses will have on MPC's system lambda costs by month. The Commission believes the inclusion of transmission level line losses will lend support the Company's proposed seasonal definition. Therefore, the Commission chooses to accept the Company's proposed five month winter, seven month summer seasonal definition.

Table 4. MPC's System Lambda Comparison ($/MWH)

Season	System Lambda	Energy Losses	System Lambda With Losses
Winter			
January	$20.0	5.04%	$21.0
February	$20.5	9.55%	$22.5
March	$19.5	10.97%	$21.6
November	$18.1	9.85%	$19.9
December	$16.7	7.69%	$18.0
	--------		--------
Average Winter:	$19.0		$20.6
Summer			
April	$11.3	5.06%	$11.9
May	$12.3	5.34%	$13.0
June	$12.1	4.91%	$12.7
July	$13.4	12.28%	$15.0
August	$19.4	8.00%	$21.0
September	$15.0	8.54%	$16.3
October	$17.6	7.23%	$18.9
	--------		--------
Average Summer:	$14.4		$15.5

Source: Exh. 1, pp. 2/137, 44/137

Transmission. The Commission rejects the Company's, and the industrial intervenors, criticism of the MCC's use of MDU CT costs as a proxy for MPC's marginal transmission costs. Cost of service studies, through necessity, often use regional costs. For example, MPC adjusts transmission O&M costs using a Handy-Whitman price index, which represents a regional averaged cost index (MPC RDR MCC 2-24). However, the MCC's levelization of those costs using nominal carrying charges is unacceptable (see Finding No. ??). The Commission chooses to accept the Company's marginal transmission costs on the basis that the Company's costs are more reflective of the Company's system than the MCC's costs. However, the Commission finds that several changes must occur in the calculation of marginal transmission costs before MPC's next general rate filing.

The Commission is troubled by the Company's separation of transmission projects as "new load" or "reliability" related (Exh. 1, p. 8/137). The Company determines a project to be all reliability or all new load on the basis of the primary purpose of the project (MPC RDR MCC 2-21). The Commission believes that all projects contain both "new load" and "reliability" components, and requests that MPC reflect that relationship in its next general rate filing.

Distribution. The Commission would like to address the Company's criticism of the MCC's "embedded" approach to distribution and customer costs (Exh. 6, pp. 2,3). Mr. Maxwell has testified that the Company's marginal distribution cost methodology is also based on embedded cost data (TR pp. 92-49). However, the Company has used embedded data to calculate marginal distribution costs, while the MCC has used embedded data as a proxy for marginal distribution costs. For Commission finds the Company's marginal analysis more appropriate and chooses to accept the MPC's proposed marginal distribution costs. In presenting this finding, the Commission notes that neither the Company's, or the MCC's methodology, represents a first best solution to the calculation of these costs, and the Commission will revisit this issue in future proceedings.

Customer. The Commission accepts the Company's marginal customer costs; with one exception. The Company's cost of service study indicates that meter costs for the Irrigation Class are based on the cost of a kwh meter (MPC RDR PSC 3-34). The Company admits that the inclusion of a demand charge in the Irrigation Class tariff warrants a change in meter costs as well (TR, p. 105). Therefore, the Commission requires MPC to develop separate meter costs, marginal customer costs, and customer charges, for demand metered irrigation customers using data contained in the record of this proceeding.

Allocated Costs. Fuctionalized costs are classified to energy, demand, and customer. These costs are then allocated to customer classes and seasons.

The Commission accepts the Company's proposal to allocate energy costs to seasons and customer classes on the basis of seasonal energy consumption and line losses. The Commission finds the Company's methodology straightforward, easily understood, and similar to the methodology proposed by the MCC.

The Commission would first like to present a discussion on the allocation of demand costs to customer classes by season before presenting its findings. The MPC and MCC proposals for allocating capacity costs to customer classes by seasons are explained in Findings ??-??, and ??-??, respectively. The primary difference in the two methodologies is that the Company uses an average of summer coincident peaks, while the MCC uses the single largest summer coincident peak, to allocated capacity costs to seasons.

The Company advocates the use of an average summer peak stating that the summer peak for its various customer classes do not occur in the same month, and using more than one month rather than the average would have an adverse impact on some classes (Exh. 6, p. 5). Additionally, the Company justifies the use of a single winter peak on the basis that, "The winter peaks are caused mostly because they are weather sensitive. In the summer, that is not necessarily true." (Exh. 6, p. 5).

Under cross examination, Mr. Maxwell revealed that the MPC's various customer classes do not peak in the same winter month, much the same as the summer (TR pp. 94-96). Furthermore, Mr. Maxwell indicated that not only is the winter peak weather sensitive, the summer peak is also weather sensitive.

> A. You risk a greater chance of not including some customers in the summer if you pick one single month out.
>
> Q. Why is that?
>
> A. Because peaks--as I stated, the winter peaks are caused mostly because they are weather sensitive. In the summer, that is not necessarily true.
>
> Q. You don't believe that the summer load is weather sensitive?
>
> A. Not as weather sensitive as the winter load is, no.
>
> Q. It's just a matter of degree?
>
> A. Yes.

While the data included in this filing indicates that MPC is currently a winter peaking utility, the data also indicates that the summer peak at the generator is within 12 percent of the winter peak (MPC RDR IND 2-1, p. 18/23). The Commission is concerned that MPC's summer peak may approach, or exceed, its winter peak at some point in the future. If that should ever occur, the Commission believes that summer rates should reflect the single summer peak, not the average summer peak.

The Commission finds that the Company is not in danger of becoming a summer peaking utility at this time, and accepts the Company's proposal to allocate generation capacity costs to customer classes on the basis of a single coincident winter peak and an average of summer coincident peaks, adjusted for line losses. In doing so, the Commission notes that is following its precedent set in Order No. 5051d, Finding Nos. 130-135. However, the Commission also finds that the issue of a single summer coincident peak verses an average of the summer coincident peaks must be addresses in its next general rate filing.

Reactive Power. In Docket No. 83.9.67, MPC's last COS filing, the Commission issued the following finding:

> 97. In the next electric rate case that deals with class cost of service and rate design the Company must address the issue of a reactive power charge for the electric contract customers. The marginal cost of reactive power demand and the appropriate measure of billing determinant units must be addressed (Order No. 5051f).

The Company filed motions for reconsideration in Docket No. 83.9.67, requesting that the Commission reconsider Finding No. 9. The Commission denied the Company's request (Order No. 5051g, Finding Nos. 16 & 17).

The Company chose not to comply with these findings in this proceeding. The Company's response to data request PSC 1-8 part iii. provides the Company's reasons:

> The MPC testimony is that, given the manpower and budget constraints exercised in the Company following Colstrip Unit No. 3 rate decision Docket No. 84.11.71, the resources were not available to provide the metering installations nor for the consequent study necessary to develop the proper costing for reactive power for the Industrial Class for this filing. Without such a study, it is not self-evident that a reactive power charge is a worthwhile billing determinant.

The Commission requires MPC to address the issue of the marginal cost of reactive power, in compliance with Order No. 5051f, Finding No. 97, in its next general rate filing. The appropriateness of a reactive power demand charge must also be addressed. If MPC chooses not to comply with this finding, the

Commission will impute a marginal cost of reactive power for inclusion in the Company's COS study.

PART C

RECONCILIATION

Introduction

The end result of a marginal cost study, such as MPC's and MCC's, is a marginal cost based revenue requirement. More likely than not, the marginal cost revenue requirement will not equal the Company's embedded revenue requirement. When the two revenue requirements are not equal, a "reconciliation" procedure is needed to reconcile marginal cost revenues to embedded revenues. This reconciliation process can use many methodologies, and the purpose of this section is to review the different procedures proposed in this docket. First the Commission will review each proposed reconciliation methodology, then it will present its findings.

MPC Reconciliation

The Company's reconciliation procedure is based on an equi-proportional reconciliation methodology. Under this approach, each rate class recovers an equal percentage of its marginal cost revenue requirement. The Company's equi-proportional reconciliation would set each customer class' revenue requirement at approximately 74 percent of the full marginal cost revenue requirement (MPC RDR PSC 1-31, p.1/11).

The Company's proposed equi-proportional reconciliation results in a 34.8 percent increase in the Irrigation Class' revenue requirement (MPC RDR PSC 1-31, p.9 of 11). However, the Company, as a matter of Company policy, is proposing no increase in that class' revenue requirement (Exh. 12, pp. 8-12). Mr. Haffey explains the Company's position:

> ... the Company does not propose a change to the total Irrigation Class revenue responsibility, increase or decrease, for reasons not related to a calculated class revenue requirement, no matter how that number might differ from the current class revenues (MPC RDR PSC 3-26).

Rather, the Company proposes to spread the Irrigation Class' increased revenue requirement to MPC's other rate classes by increasing all other rate class' revenue requirements by 0.4659 percent (MPC RDR PSC 1-31 p. 9/11, and Exh. 12, JDH-1). Table 5 below shows the Company's present 1985 test year revenues, the Company's proposed reconciled revenues, and the percentage change from present to proposed revenue levels by customer class.

Table 5. MPC Reconciliation (000's of dollars)

Class	Present Revenues	Reconciled Revenues	Change in Revenues
Residential	88,561	90,170	1.82%
General Service	98,054	94,381	(3.75%)
Industrial	45,385	46,546	2.55%
Irrigation	3,188	3,188	0.00%
Street Lighting	4,662	4,966	7.43%
Post-Top Lighting	438	618	41.10%
Yard Lighting	2,216	2,595	17.11%

Source: MPC RDR PSC 1-31, and Exh. 12, JDH-1

MCC Reconciliation

The MCC's COS study indicates that marginal cost pricing would produce revenues which exceed the Company's embedded revenue requirement. Mr. Drzemiecki proposes to reconcile marginal cost revenues to the embedded revenue requirement by applying a factor of 0.947174 to Bulk Power marginal costs (Exh. 19, p. 52).

After the Bulk Power adjustment is completed, MCC proposes additional adjustments be made to reconciled marginal revenue requirement. The MCC's reconciliation would require an increase in the Irrigation Class' revenue requirement of 78.98 percent (Exh. 19, p. 54). However, Mr. Drzemiecki proposes that the revenue increase to the Irrigation Class be limited to 11.6 percent (TR, p. 375). Similarly, Mr. Drzemiecki proposes that all lighting classes receive the same revenue increase as the Irrigation Class, or 11.6 percent (Exh. 19, p. 61, and TR, p. 375). Additionally, Mr. Drzemiecki proposes to spread the foregone revenues associated with 28 MW of the EEI load back to each service class based on their allocated cost of service (TR, p. 375). Lastly, the MCC recommends placing the irrigation and lighting class' revenue deficiency on the general service and industrial rate class (TR, p. 375-376).

In total, Mr. Drzemiecki's reconciliation adjustments result in the following revenue requirement impacts; 1) Residential customers would receive an increase of approximately one percent, 2) Irrigation and all lighting classes would receive an 11.6 percent increase 3) the General Service class would receive a 2.2 percent decrease, and 4) the Industrial class revenue requirement would remain unchanged (TR, pp. 375,376)

<u>HRC Reconciliation</u>

Dr. Power has not submitted a marginal cost service study in the instant docket, and therefore, HRC does not propose a reconciliation procedure. However, Dr. Power supports the Company's proposed reconciliation procedure:

> Since marginal costs are unlikely to match the historical accounting costs that are the basis of the utility's revenue requirement, they must be adjusted so that the utility earns only its authorized fair rate of return. This needs to be done in a way that least distorts the marginal cost information and is even handed with respect to all customer classes. MPC appropriately makes this adjustment by proportionally reducing the marginal cost responsibility of all classes so that cost responsibility matches MPC's revenue requirement (Exh. 16, p. 6).

<u>ASARCO et al. Reconciliation</u>

Mr. Michael did not present a cost of service study in this proceeding, and in general does not endorse marginal cost studies (Exh. 24, p. 2). However, Mr. Michael has utilized the Company proposed equi-proportional reconciliation method to develop various class revenue requirements based on alternative cost-of-service studies in this proceeding (ASARCO et al. RDR PSC 1-13).

Commission Decisions on Reconciliation

The Commission chooses to follow its precedent established in Order No. 5051d, Docket No. 83.9.67, and accept the equi-percent reconciliation of classified costs as proposed by MPC, supported by the HRC, and used by ASARCO et al.

As a preliminary matter, the Commission requires MPC to include all known revenue requirement changes, to the date of this Order (e.g. Rate Moderation Plan and PSC funding tax effects), in establishing a revenue requirement for the purpose of reconciling marginal cost revenues in the revised marginal cost study required by this Order.

MCC's Proposed Reconciliation. The MCC's proposed reconciliation procedure is rejected for the following reasons. The Commission finds, as it has found in previous orders, MCC's reconciliation of Bulk Power costs appears to be an application of inverse "inverse-elasticity" pricing. To repeat the Commission's objections to MCC's reconciliation procedure in this and previous dockets:

> The MCC's proposal to reconcile just Bulk Power costs does not work to maximize welfare...Clearly, the elasticity of demand

> is relatively larger for the energy and demand components of Bulk Power costs than for, say, customer costs...It follows that from an economic viewpoint one would attempt to minimize deviations from Bulk Power costs relative to say, customer costs." (Order No. 5219b, Finding No. 314, Docket No. 86.5.28, and Order No. 5036a, Finding No. 203, Docket No. 83.9.68).

Reclassification of Marginal Costs. The Commission would also like to comment on Mr. Drzemiecki's justification of reassigning marginal capacity costs to marginal energy costs on the basis of embedded costs (Exh. 18, p. 46). The Commission does not find the witness' argument valid. The Commission believes that the results of a marginal cost study should stand on its own merits, and that the demand and energy relationship of embedded costs do not justify a reclassification of marginal costs.

Degree of Accuracy. The Commission rejects Dr. Power's "degree of accuracy" arguments as supported by Mr. Michael, ASARCO et al. (Exh. 16, p. 13-22, and Exh. 24 pp. 20,21). Inaccuracies are inherent in any COS study. These inaccuracies should not be the basis for rejecting, or diminishing, the results of a marginal cost study.

Irrigation. The Commission would first like to review the treatment of MPC's Irrigation Class in past dockets before presenting its findings in this docket. In Docket 80.4.2, the MPC proposed a 338% increase in the Irrigation Class' revenue requirement. The Commission-accepted COS study justified a 125% increase, and the Commission required that the increase be limited to 63% (Order 4714d). The Commission also recognized that the Irrigation Class was being subsidized:

> This Order provides an irrigation rate that is 1) explicitly subsidized by all other ratepayers and 2) reflects a promotional structure at a time when each additional unit of sales adversely effects all other ratepayers. The Commission intends to rectify both of these deficiencies in the future (Order 4714d, Finding No. 78, Docket No. 80.4.2).

The Commission's next decision regarding the Irrigation Class' revenue requirement occurred in Docket No. 83.9.67. In that Docket, MPC proposed a 55% increase in Irrigation revenue requirements. The Commission, believing that the reconciliation required in the Order would justify a reduction, froze the Irrigation Class' revenue requirement at existing levels (Order 5051d, Finding No. 171).

In this proceeding, while the Company's COS study justifies a 34.8 percent increase in the Irrigation Class' revenue requirement, MPC is proposing no change in revenue requirement. The Commission, following its long established precedent of requiring MPC's Irrigation Class to recover a greater and greater percentage of its marginal costs, accepts the MCC's proposal to increase MPC's Irrigation Class' revenue requirement by 11.6 percent. In doing so, the Commission notes that it is accepting a recommendation that is based on a reconciliation procedure that was rejected by the Commission. However, the Commission finds that the MCC proposed 11.6 percent increase is moderate when compared to the 34.8 increase justified by the Company's marginal cost study.

The Commission accepts the Company's proposal to spread the revenue deficiency created by limiting the Irrigation Class' revenue increase to 11.6 percent to all other rate classes based on an equi-percent increase in revenue requirements.

CONCLUSIONS OF LAW

1. The Applicant, Montana Power Company, furnishes electric service to consumers in the State of Montana and is a "public utility" under the regulatory jurisdiction of the Montana Public Service Commission. Section 69-3-101, MCA.

2. The Commission Properly exercises jurisdiction over the Applicant's rates and operations. Section 69-3-102, MCA and Title 69, Chapter 3, Part 3, MCA.

3. The Commission has provide adequate public notice of all proceedings and opportunity to be heard to all interested parties in this Docket, Title 2, Chapter 4, MCA.

ORDER

1. The Montana Power Company shall file a cost of service study in compliance with this Order.

2. The Cost of service study filed shall comport with all Commission determinations set forth in this Order.

3. The Cost of service study filed shall be received no later than 21 days after issuance of this Order.

4. Docket Nos. 86.6.29, 85.9.40, 85.11.49, and 85.12.50 are consolidated into this Docket.

5. All motions and objections not ruled upon are denied.

DONE AND DATED this 14th day of April, 1988, by a 4-1 vote.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

CLYDE JARVIS, Chairman

HOWARD L. ELLIS, Commissioner

TOM MONAHAN, Commissioner
Voting to dissent. No dissent written.

DANNY OBERG, Commissioner

JOHN B. DRISCOLL, Commissioner

ATTEST:

Carol A. Frasier
Commission Secretary

(SEAL)

NOTE: Any interested party may request that the Commission reconsider this decision. A motion to reconsider must be filed within ten (10) days. See 38.2.4806, ARM.